A Novel Load Transfer Scheme for Peak Load Management in Rural Areas

Michael T. Wishart, *Member, IEEE*, Jon Turner, Lasantha B. Perera, *Member, IEEE*, Arindam Ghosh, *Fellow, IEEE*, and Gerard Ledwich, *Senior Member, IEEE*

***Abstract*—This paper proposes a novel peak load management scheme for rural areas. The scheme transfers certain customers onto local nonembedded generators during peak load periods to alleviate network under voltage problems. This paper develops and presents this system by way of a case study in Central Queensland, Australia. A methodology is presented for determining the best location for the nonembedded generators as well as the number of generators required to alleviate network problems. A control algorithm to transfer and reconnect customers is developed to ensure that the network voltage profile remains within specification under all plausible load conditions. Finally, simulations are presented to show the performance of the system over a typical maximum daily load profile with large stochastic load variations.**

***Index Terms*—Nonembedded generation, peak load management, peak load shaving, rural distribution planning, single-wire earth return (SWER).**

I. Introduction

ELECTRICITY networks must be designed to supply peak loads to ensure acceptable reliability. The load factor is a critical indicator for utilities since it represents the ratio between average load (which largely determines their income) and peak load (which largely determines their capital cost). Rural areas typically suffer from low load factors on most of their feeders due to low customer densities coupled with low load diversities resulting from the lack of industrial and commercial loads. This low load factor, coupled with high costs (related to the long distances), makes the supply of low-cost electricity to rural areas a challenging prospect.

Many rural distribution systems in different parts of the world (including Australia, Canada, the U.S., and South Africa) were constructed 20–50 years ago and are reaching their capacity due to natural load growth. The cost of conventional line upgrades, given the long distances and low customer densities, is in many cases prohibitive, especially in the current economic climate. Conventional rural feeder upgrades could typically involve an investment of millions of dollars. And this could be to alleviate a peak load problem which occurs for relatively few hours a year to relatively few customers. Therefore some alternative strategies, such as demand side management and distributed generation, must be investigated as possible solutions to address what is essentially a short term peak loading problem.

This paper reports on a feasibility study done for Ergon Energy on the use of nonembedded (or off-grid) generation to perform peak load shaving or "peak lopping" on a rural feeder. Ergon Energy is the utility supplying the vast majority of the geographical area of Queensland Australia, with the exception of the densely populated south-east (i.e., Brisbane and the Gold Coast) [1].

The basic concept is to transfer certain customers onto a local diesel generator supply during peak loading periods to reduce the demand and improve the voltage profile of the network. These generators can, in concept, be either existing customer-owned generators, or alternatively generators installed specifically by the utility. The scheme is configured to result in no loss of power or voltage transient to the customer. The diesel generators can also be used as a stand-by power source during power outages.

For this scheme to be practical to the electricity utility, customers need to take responsibility for the fuelling and maintenance of the generators. This is because it is economically and practically unfeasible for the utility to fuel and maintain a fleet of widely geographically distributed small diesel generators. The economic incentives for participating customers are a separate issue being worked on within Ergon Energy.

Little has been published on this topic. There have been a few publications on rural-based embedded (or grid-connected) generation schemes (e.g., [2]–[4]), where remote generators are connected to the distribution system for peak shaving and system support. These systems offer the advantage over the nonembedded scheme that the generator supports a greater part of the network and, therefore, more customers. However, the protection/islanding, regulatory, control, and maintenance issues [5]–[7] associated with widespread embedded generation on rural networks, have resulted in a reluctance of many distribution companies (including Ergon Energy) to pursue these systems in the short term.

This paper shows that nonembedded systems can also be of value to rural distribution by alleviating network voltage problems occurring during peak network loads and deferring major capital upgrades. These avoid the complexities associated with embedded generation while still addressing the peak load issue.

Manuscript received June 15, 2010; revised August 24, 2010; accepted September 24, 2010. This work was supported by the Energy Networks Association through the Australian Strategic Technology Programme. Paper no. TPWRD-00453-2010.

M. T. Wishart, L. B. Perera, A. Ghosh, and G. Ledwich are with the School of Engineering Systems, Queensland University of Technology, Brisbane QLD 4001, Australia (e-mail: michael.wishart@qut.edu.au).

J. Turner is with Ergon Energy, Rockhampton QLD 4700, Australia (e-mail: jon.turner@ergon.com.au).

Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TPWRD.2010.2082573

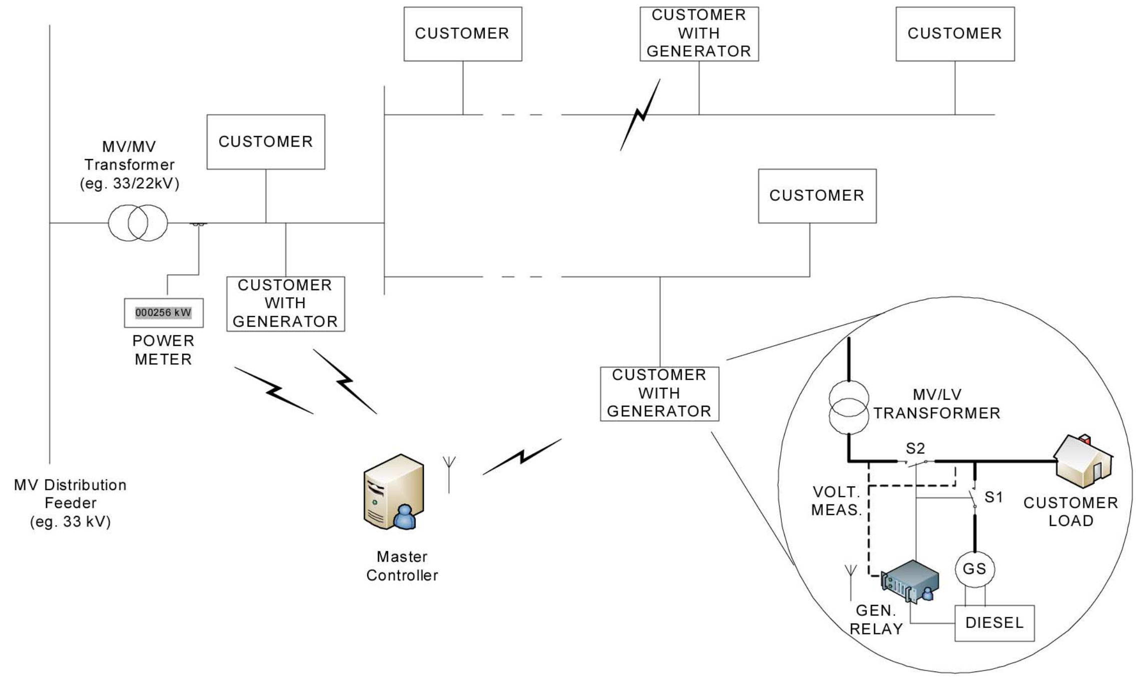


Fig. 1. Overview of load transfer control scheme.

This paper has three main contributions. First, it describes a methodology for choosing the most effective locations for installing local generators to maximize the benefit to the network. Second, it calculates the number of generators that need to be installed to alleviate network problems. Third, it proposes a control algorithm for this scheme. The algorithm controls the location and timing of transfers to local generation and subsequent reconnections. The proposed system must respond rapidly to load changes while avoiding spurious operation due to instantaneous stochastic load changes. Note that this same algorithm could be used for other types of generators and even energy storage units.

The proposed scheme is described by way of a case study on a single-wire earth return (SWER) feeder in rural Queensland. However it should be noted that the methodology and proposed control system is not specific to SWER systems, it can be applied to three-phase rural systems as well.

II. Overview of the Proposed Control Scheme

Fig. 1 shows a schematic of a typical rural network with the proposed peak load transfer scheme. In many sparsely populated rural areas, the customers are supplied directly from medium voltage via dedicated medium-voltage/low-voltage (MV/LV) transformers. The basic concept of the control scheme is to transfer certain customers onto local diesel generator supply during peak loading periods to reduce the demand and improve the voltage profile of the network. The scheme may be thought of as a kind of pre-emptive load shedding.

In the proposed scheme, a number of distributed diesel generators are installed at certain specific customer locations. These generators are located to result in the best voltage performance on the network (as discussed in Section IV). The number of generators required is also discussed in Section IV, but typically they are required at only a small proportion ($\sim$10%) of the customers.

Each generator is equipped with an intelligent relay, which communicates with a master controller as shown in Fig. 1. In this study, third-generation (3G) cellular communication is used since it is the most cost effective communication medium for these rural networks and the specific area in question has good coverage.

The intelligent relays measure the local voltage and real and reactive power consumption and send this information to the master controller every minute. The master controller processes this information, along with the total feeder load measured at the supply transformer. If the network experiences poor voltage performance as a result of high peak loads, the master controller sends "initiate transfer" commands to specific relays. Upon receiving the "initiate transfer" command, the intelligent relays commence a "bumpless" load transfer, transferring the consumer load from the network supply onto its local generator supply. This reduces the load on the network and increases the network voltage. The "bumpless transfer" is implemented by starting the diesel generator, running it up to speed, synchronizing to the network by closing switch S1 and finally opening the supply switch S2. This ensures that the customer does not experience a momentary outage or voltage dip during transfer. The time taken to complete a bumpless transfer is generator dependent and can be compensated for in the master controller. The master controller also sends an "initiate reconnection" command to certain relays when the network voltage starts to recover. Upon receiving this command the intelligent relay reconnects the customer load to the network in the reverse sequence to before. The relay senses the voltage across switch S2 to ensure that the switch is closed when the phase difference is near zero.

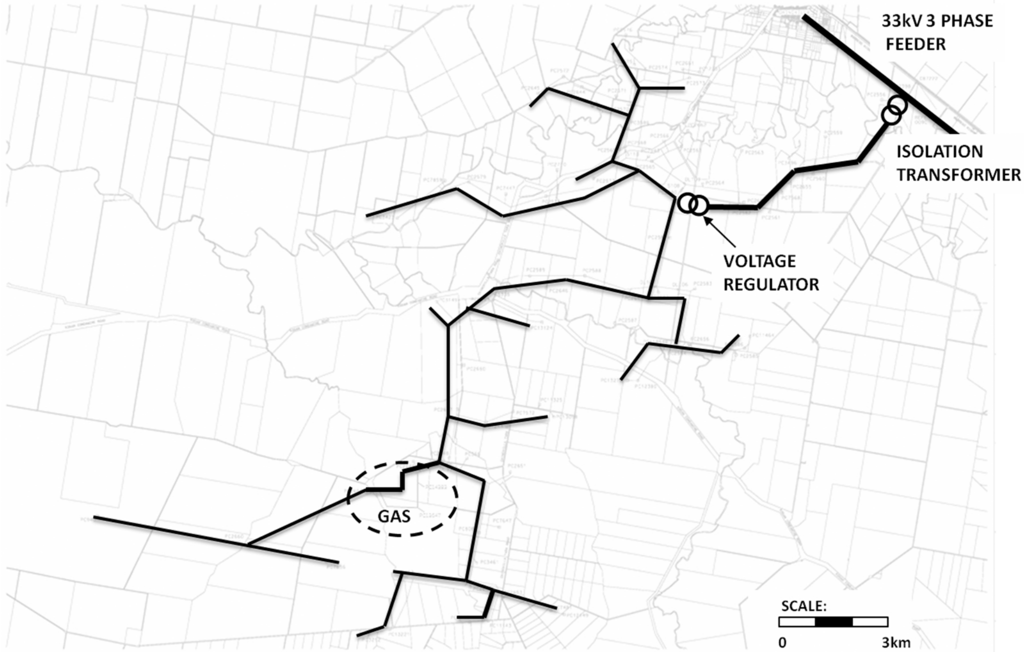


Fig. 2. Wambo Creek SWER schematic.

The details of the master controller algorithm to determine which loads to transfer and the timing thereof are described in Section V.

One potential criticism of this scheme is that it relies on a reasonably extensive two-way communication system between the master controller and the intelligent relays. An alternative system could be proposed with a one-way broadcast system of communication and more distributed/local control. However this one-way system would inevitably have some performance disadvantages compared to the two-way system with virtually no cost benefit. This is because cellular communication systems are generally nowadays the most cost effective form of communication in rural areas. In this scenario, there is virtually no cost advantage of reducing the system to a one-way broadcast-based system.

For the practical implementation, it is necessary to consider communication failure scenarios such as intermittent signals or a total failure of communications. Full treatment of this topic is beyond the scope of this paper, however in summary, state machines have been developed for each communications failure scenario classified by type of failure (e.g., total or intermittent failure) and timing (e.g., failure while generators are inactive, failure during "initiate transfer" sequence, failure while load is transferred, etc.). Specific responses are programmed to reflect the desired response of the system.

It is apparent that it is important to determine the minimum number of required generators as well as their optimum locations. This is system specific. The next section therefore introduces a case study and the section thereafter continues to address the optimum number and location of generators.

III. Case Study: Wambo Creek SWER

Fig. 2 shows a schematic of Wambo Creek, an SWER system [8] in Central Queensland, Australia. SWER systems are very common in rural Australia as well as in many other rural parts of the world including Canada, New Zealand, South Africa, and China. They are a cost-effective way of electrifying large sparsely populated geographical areas. Ergon Energy has around 64 000 km of SWER representing around 45% of their total distribution network length (but supplying fewer than 5% of their customers) [1].

The Wambo Creek 12.7 kV SWER system is supplied from a 33 kV feeder originating from a substation approximately 6 km away. The scheme has a 200 kVA isolating transformer supplying 138 km of overhead SWER feeder and 88 customers. All customers have their own MV/LV supply transformers. A voltage regulator is installed approximately 14 km down the main SWER feeder with a control range of $\pm 10\%$. The section of the SWER feeder between the isolating transformer and the voltage regulator is constructed with 3/4/2.50 ACSR (Aluminum Conducting Steel Reinforced) conductor. Most of the remaining sections use 3/2.75 galvanized steel conductor with the exception of small sections in the vicinity of the gas field which uses the afore mentioned ACSR conductor.

Most customer loads are either homesteads or bore pumps with supply transformers rated at 10 or 5 kVA. There are a few farming customers with 25 kVA transformers and there is a gas-field customer (circled) near the end of the line with a 50 kVA transformer.

The 15 minute maximum demand at the isolating transformer has been measured at 284 kVA. This is above even the cyclical rating of the 200 kVA isolation transformer; however, the conductor is well within its thermal rating.

Load information is sparse. Only customer transformer ratings and annual customer energy consumption figures are available along with a typical load profile at the isolation transformer. This limited data set is quite typical in the industry today.

TABLE I
WAMBO CREEK LOAD-FLOW RESULTS

Load Assumption	**Average of lowest 10% of customer voltages [pu]**	**Lowest individual customer voltage [pu]**
Loads in proportion to customer transformer rating	0.812 pu	0.811 pu
Loads in proportion to customer annual consumption	0.861 pu	0.860 pu

Load-flow studies indicate under voltage problems in a large area near the end of the network at peak demand. Table I shows the voltage performance under two different load assumptions. These results show voltages well below the Australian limits of $\pm 6\%$. This, together with the fact that the maximum demand exceeds the cyclical transformer rating, indicates that the Wambo Creek system is in need of an upgrade of some sort.

As a rough indication, a conventional upgrade of this system, consisting of converting the SWER system to a three-phase system would cost in the order of US$6M (including capital, installation, and labor costs). The nonembedded generator scheme offers the potential of considerable savings relative to this cost, particularly if generators are required at relatively few customer sites.

Other more conventional voltage support solutions are of limited value for this type of rural network. Capacitive voltage support has limited impact due to the high R/X ratio of the conductor. Additional series voltage regulators can improve voltage profiles but result in transient over voltages in response to sharp load decreases.

IV. NUMBER AND LOCATION OF REQUIRED GENERATORS

A key question is to determine how many generators are required and the best locations for these generators. System studies are required to determine this. The procedure followed in this paper is to firstly determine a ranked list of the best generator sites and then determine how many are required via a systematic search.

A. Location of Required Generators

There are a number of factors influencing the optimum locations for the nonembedded generators including technical, commercial and operational factors. This paper focuses exclusively on the technical factors.

From a technical point of view, there are two network issues to solve; the capacity problem evident at the isolation transformer and the under voltage performance of the network. Of course these issues are inter-related; however, the undervoltage problem is certainly more challenging to address.

For voltage performance, the best customer locations are those which result in the greatest change in network voltage for transfer of that customer load. We consider the "greatest change in network voltage" to be the largest and most widespread changes in network voltage. To be more precise, for each node i we define a voltage sensitivity parameter ρ_i to be the average change in node voltages due to a transfer of the load at node i, i.e.,

$$\rho_i = \frac{\sum_{m=1}^{N} \Delta V_m}{N} = \frac{\sum_{m=1}^{N} \frac{\partial V_m}{\partial P_i} \cdot \Delta P_i + \frac{\partial V_m}{\partial Q_i} \cdot \Delta Q_i}{N} \tag{1}$$

where N is the total number of nodes, and ΔP_i, ΔQ_i are the real and reactive powers to be transferred at the node.

So the customer locations with the highest ρ values will be those that result in the biggest average nodal voltage change and, therefore, the best locations for generator siting.

From (1), to calculate ρ, we need to calculate the voltage sensitivities $\partial V_m/\partial P_i$ and $\partial V_m/\partial Q_i$. These may be determined directly from the elements of the inverse of the power system Jacobian $\mathbf{J^{-1}}$, calculated by power system analysis packages during Newton–Raphson load-flow computations [9]

$$\begin{bmatrix} \Delta\delta \\ \Delta V \end{bmatrix} = J^{-1} \cdot \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \tag{2}$$

where

$$J^{-1} = \left[\begin{array}{ccc|ccc} \frac{\partial \delta_1}{\partial P_1} & \cdots & \frac{\partial \delta_1}{\partial P_N} & \frac{\partial \delta_1}{\partial Q_1} & \cdots & \frac{\partial \delta_1}{\partial Q_N} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial \delta_N}{\partial P_1} & \cdots & \frac{\partial \delta_N}{\partial P_N} & \frac{\partial \delta_N}{\partial Q_1} & \cdots & \frac{\partial \delta_N}{\partial Q_N} \\ \hline \frac{\partial V_1}{\partial P_1} & \cdots & \frac{\partial V_1}{\partial P_N} & \frac{\partial V_1}{\partial Q_1} & \cdots & \frac{\partial V_1}{\partial Q_N} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial V_N}{\partial P_1} & \cdots & \frac{\partial V_N}{\partial P_N} & \frac{\partial V_n}{\partial Q_1} & \cdots & \frac{\partial V_N}{\partial Q_N} \end{array}\right].$$

The Jacobian of the Wambo Creek network was determined using the open source "Power System Analysis Toolbox" (PSAT) [10] which runs on Matlab and Octave software packages. Note that PSAT only models three-phase networks; therefore, for the case study, the SWER network had to be converted into its equivalent three-phase form.

The Jacobian (and, therefore, the voltage sensitivities) depends on the network topology and parameters as well as on the load. To get an idea of the sensitivity of the Jacobian to load, it was calculated for two load-flow cases; a base case where the individual loads are assigned in proportion to their transformer ratings, and a modified case, where each load was changed randomly by an amount of the same order as the original load (but with the aggregated load remaining approximately constant). Fig. 3 shows the resulting self-sensitivities $\partial V_i/\partial P_i$ and $\partial V_i/\partial Q_i$ in volts per kilovolt-ampere on the MV network for each of the 102 nodes for the base case (white bars) and the random case (black bars).

Despite the large change in load distribution, the values remain similar and their order (from highest value to lowest value) remains identical. This shows that their voltage sensitivity is only weakly dependent on the load.

Note that for each node, the voltage sensitivity to changes in real power $\partial V_i/\partial P_i$ is greater than the voltage sensitivity to changes in reactive power $\partial V_i/\partial Q_i$. This is due to the highly resistive nature of the network (high R/X ratio).

This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.

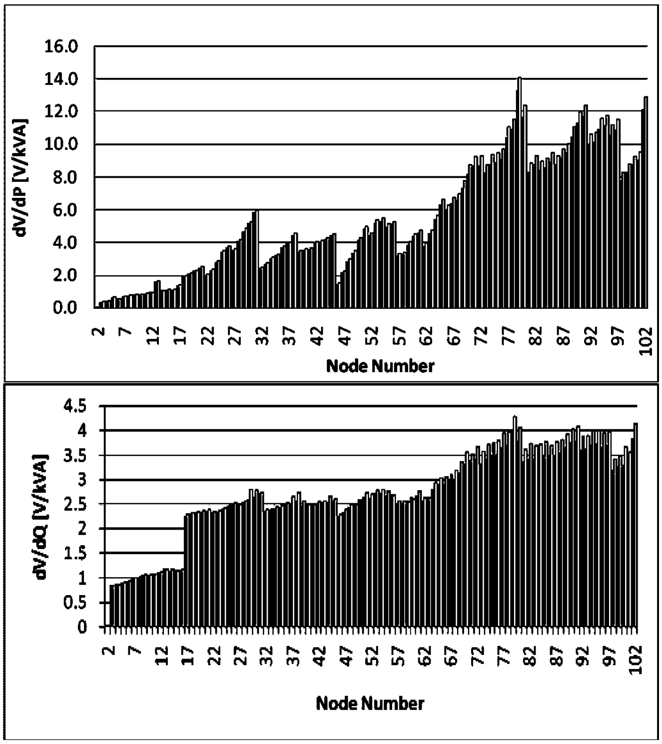


Fig. 3. Voltage self-sensitivities—base case and random loadings.

Equation (1) also shows that the best locations are dependent on the customer loads ΔP_i, ΔQ_i during the network peak loading period. An estimate therefore has to be made of the likely load of each customer during the network peak. This is by its very nature fraught with difficulty and subject to a high degree of uncertainty [11]. The authors approach is to propose a method of choosing sites and then to check the performance of the system using those sites via multiple simulations with differing random loads.

As mentioned previously, the load information is limited to the customer annual consumption and transformer ratings. However, even if more detailed information was available (e.g., from smart meters), the individual customer loads change stochastically with time, so the exact composition of the load at the time of peak demand is inherently uncertain.

To determine the most likely customer load P_i, Q_i, the following assumptions are made.

- The value for each likely customer load at the time of maximum demand is proportional to both their annual energy consumption and their transformer rating. These are common assumptions traditionally used in power system planning.
- The total aggregated network load is equal to the highest recorded 15 minute averaged reading of 284 kVA.
- All customer loads have a lagging power factor of 0.85. This relatively low value was chosen because motors (pumps) are thought to dominate the rural loads.

That is, the load at node i:

$$S_i = k \cdot S_{\mathrm{trf},i} \cdot E_{a,i}$$
$$\cos\theta = 0.85$$

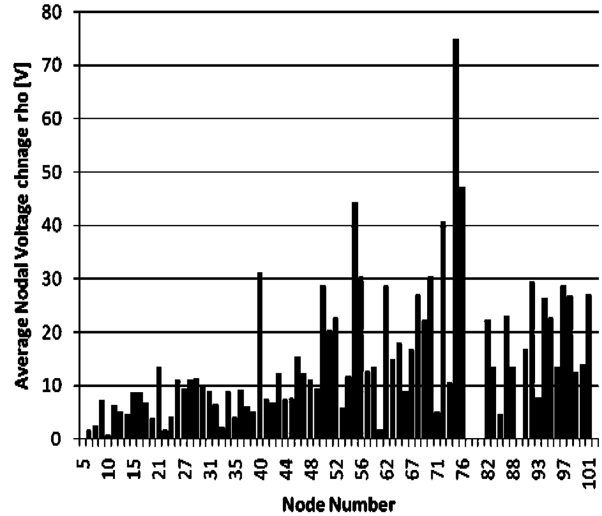


Fig. 4. ρ values determining the best generator location.

$$\sum_{i=1}^{N} \|P_i + jQ_i + P_{\mathrm{loss}} + jQ_{\mathrm{loss}}\| = 284\,\mathrm{kVA} \tag{3}$$

where $S_i = P_i + jQ_i$; $S_{\mathrm{trf},i}$ is the rating of the customer i transformer; $E_{a,i}$ is the annual energy consumption of customer i; and k is a constant. Using these assumptions, a load flow was conducted, the voltage sensitivities $\partial V_m/\partial P_i$ and $\partial V_m/\partial Q_i$ extracted from the inverse Jacobian, and the ρ values were calculated for each load. Fig. 4 shows a graph of the ρ values which represent the average change in all node voltages for the likely change in transferred load at that node.

They therefore give an indication of the value associated with locating a generator at that site. Thus the best ten sites are the ten nodes with the highest values shown in Fig. 4.

B. Number of Generators Required

Having determined a ranking of the best generator sites, it is necessary to determine the number of installed generators that are required to bring the network voltages back to within specification. Since the loads vary stochastically, this again requires a careful approach.

Each nominal load value can be derived from the peak network load (284 kVA), the customer transformer ratings and annual energy consumption as described in Section A above. However, in reality when the network is at its peak load, the individual customer loads are highly unlikely to equal these derived values. Studies by Herman *et al.* [12], [13] have shown that typical middle-class domestic customer loads in South Africa best fit a Beta probability density function (PDF). Load data presented from a U.K. study also seem to fit the Beta PDF [14]. The Beta distribution, described in the Appendix, is bounded at 0 and 1, so its upper limit can be scaled to match the customers' circuit-breaker values.

To determine the number of generators required, the authors adopted the systematic approach shown in Fig. 5. The number of transferred loads is incremented from zero up to a total of 20. For each increment, 50 load flows are performed with the loads

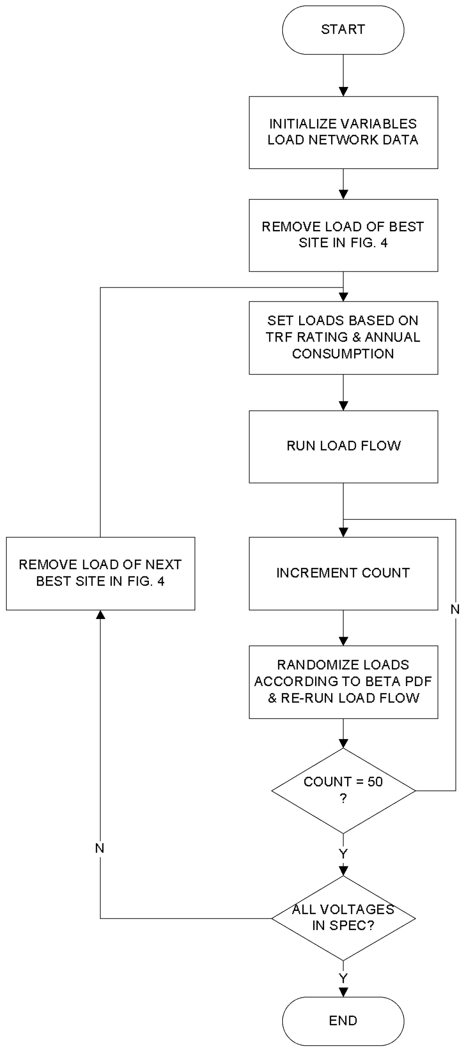


Fig. 5. Flowchart to determine the number of required generators.

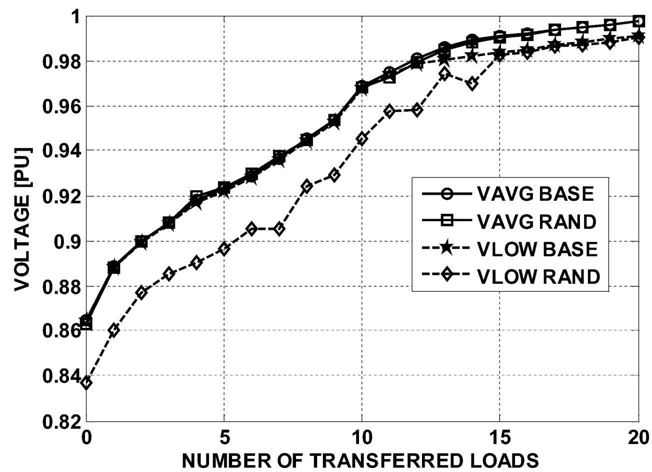


Fig. 6. Voltage performance of the lowest 10% and lowest individual node. Loads are randomly distributed according to the Beta PDF with mean values weighted by annual consumption and transformer rating.

distributed according to the Beta PDF. The lowest 10% of node voltages were recorded in each load-flow run.

Fig. 6 shows the results. VAVG BASE is the average of the lowest 10% of node voltages for the base load flow (i.e., the load flow with loads calculated according to Section IV-A). VLOW BASE is the lowest individual node voltage. VAVG RAND is the average of the lowest 10% of node voltages, averaged over the 50 random load-flow runs. VLOW RAND is the worst individual node voltage from all 50 runs. It can be seen that with 10 generators/transferred loads, even the worst individual node voltage from 50 random load-flow runs is above the limit of 0.94 p.u. This gives reasonable confidence that if generators are installed at the 10 best sites, the network voltages will remain in specification.

Of course, fewer generators could also be chosen with only occasional deviations below 0.94 p.u.

Note that the above mentioned analysis assumes that the load distribution at the time of peak demand is in practice weighted towards the transformer rating and annual consumption. However, if for some reason, the actual loads at the time of peak demand are statistically well below expectations then the results may in theory be worse than depicted in Fig. 6. For example, in the extreme if none of the potential generator sites are consuming load at the time of maximum demand then the network voltage will not improve by transferring these loads. This situation is of course highly unlikely in practice however it does raise the question of the system performance if the loads do not statistically follow the transformer and annual consumption weighting. To investigate this point, the loads of the top 20 potential generator sites in Fig. 4 were biased by halving their mean value and the remainder of the loads were increased so that the total feeder load remained the same. Fig. 7 shows the results. The average voltage performance is better than Fig. 6 because the 20 sites tend to be large loads near the extremity of the network so halving their value increases the average network voltage. However, the network voltage improvement as a function of number of loads transferred is lower than Fig. 6 and the required number of generators is around 12. Thus unsurprisingly the "coloring" or biasing of the load distribution has a potential cost impact. Since there is no valid reason to assume that the loads are not statistically proportional to annual consumption and transformer size, this result is presented as an indication of sensitivity; however, it was not used to influence the final number of generators chosen.

To start motor loads and minimize the potential of customer harmonic issues, it is recommended that the generators chosen are reasonably large single-phase generators (e.g., 32 kVA). Despite this relative oversizing, a preliminary costing indicates a substantial saving (>90%) compared with the conventional upgrade cost of US$6M. This saving is mainly due to the high cost of reconductoring long distances of overhead line compared to the purchase cost of 10 single-phase generators. Note that this preliminary costing is only very approximate and includes an approximate capital cost for the generators and a 20-year accumulated allowance for operational and maintenance costs (which may eventually be in the form of subsidies or incentives to the customers). Work is continuing within Ergon Energy to further develop the financial model and develop the appropriate

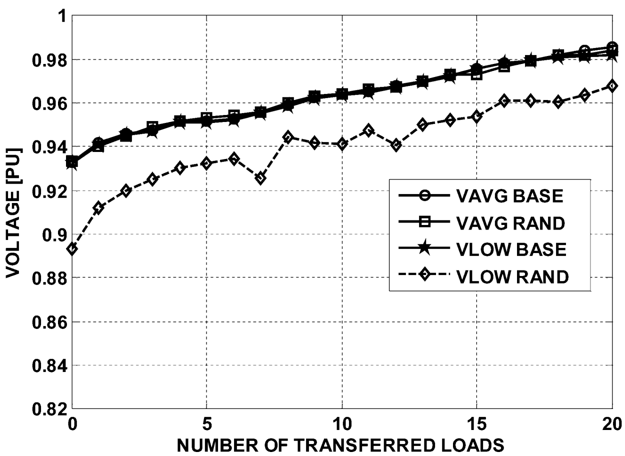


Fig. 7. Voltage performance of the lowest 10% and lowest individual node. Loads are randomly distributed according to the Beta PDF with mean values of the 20 top loads (in Fig. 4) halved.

customer incentive scheme. Nevertheless, indications are that the scheme will be financially viable.

Having determined the number and location of the required generators, the next section describes the control algorithm developed to control the transfer and reconnection of the customer loads in real time.

V. Control Algorithm

A schematic of the overall control scheme was given in Fig. 1. The master controller executes the load transfer algorithm and communicates with all of the generator relays, initiating load transfer. The key outputs of the algorithm are:

a) determination of when to initiate load transfer;
b) determination of which loads to transfer and in what sequence;
c) determination of when to reconnect the loads.

Outputs a) and c) can be done using averaged network voltage measurements obtained from the generator relays.

Output b) can be based on the voltage sensitivities and real time measured real and reactive power.

The proposed algorithm is as follows.

Step 1) Store the rows of the inverse Jacobian $\boldsymbol{J}^{-1}$ corresponding to the 10 participating customers in the master controller. This is done once-off at commissioning of the scheme and redone on any major network changes.

Step 2) Measure the node voltage V and real and reactive power P and Q at each participating site (done by the generator relays).

Step 3) Send V, P and Q from each nonembedded generator relay to the master controller every minute.

Step 4) Apply a 15 minute moving average filter to the measured V, P and Q values. This is calculated every minute.

Step 5) Calculate VL_AVG, the average of the measured moving average voltages.

Step 6) If VL_AVG is less than 0.965 p.u., then initiate the load transfer. This value is chosen since Fig. 6 shows an approximate difference of 0.25 p.u. between the averaged measured voltage and the absolute worst voltage. Therefore, keeping VL_AVG to 0.965 p.u. and above should result in the worst case voltage remaining at around 0.94 p.u.

Step 7) If load transfer is required, calculate the expected average network voltage improvement for a load transfer at each participating site by

$$\Delta V = \frac{\sum_{m=1}^{N} \frac{\partial V_m}{\partial P_i} \cdot \Delta P_i + \frac{\partial V_m}{\partial Q_i} \cdot \Delta Q_i}{N}. \quad (4)$$

Step 8) Rank the sites accordingly. This ranking is calculated online in the master controller and updated every minute.

Step 9) Initiate load transfer sequentially according to the voltage improvement ranking calculated in steps 7) and 8).

Step 10) Go back to Step 2).

Step 11) If VL_AVG rises above 0.98 p.u., initiate reconnection in reverse sequence to load transfer. Apply a 25 minute moving average filter to the reconnection. This is to effectively implement a minimum on-time for the generators.

The algorithm is therefore a type of hysteresis controller. It also contains a number of other settings to improve performance, such as a setting to limit the maximum rate of transfer/reconnection to once every 3 minutes.

VI. Control Algorithm Simulated Results

To test the validity of the algorithm it was simulated in Matlab (along with the Wambo Creek system). This simulation is a time- stepped steady state simulation. It uses consecutive (steady state) load-flow studies (utilizing the PSAT Toolbox) to generate a time-based simulation of the algorithm. Note that this is not a true time domain simulation since it does not simulate the system dynamics.

Simulations were conducted to check the performance over a number of different scenarios including:

1) Response to slowly increasing and decreasing load;
2) response to rapidly increasing and decreasing load;
3) response to maximum daily load profile;
4) response to extreme daily load profile;
5) response to maximum daily load profile with randomly varying loads.

In all cases, the system responded in a stable and predictable manner. Due to space limitations, we present only 5 above which incorporates many of the other characteristics.

The total aggregated feeder load measured at the isolation transformer was assumed to approximate a typical residential "double humped" daily load profile, with a morning peak and a larger evening peak. The individual loads were assumed to change randomly every 3 min according to the Beta PDF with $\alpha = 1.73$ and $\beta = 7.75$ as in the Appendix. It must be noted that although there is research showing that domestic loads are distributed from customer to customer according to the Beta distribution with these parameters, the load variation of each individual customer is unlikely to be as severe as this in practice. Nevertheless, it represents an extreme test case to analyze the noise immunity of the control algorithm.

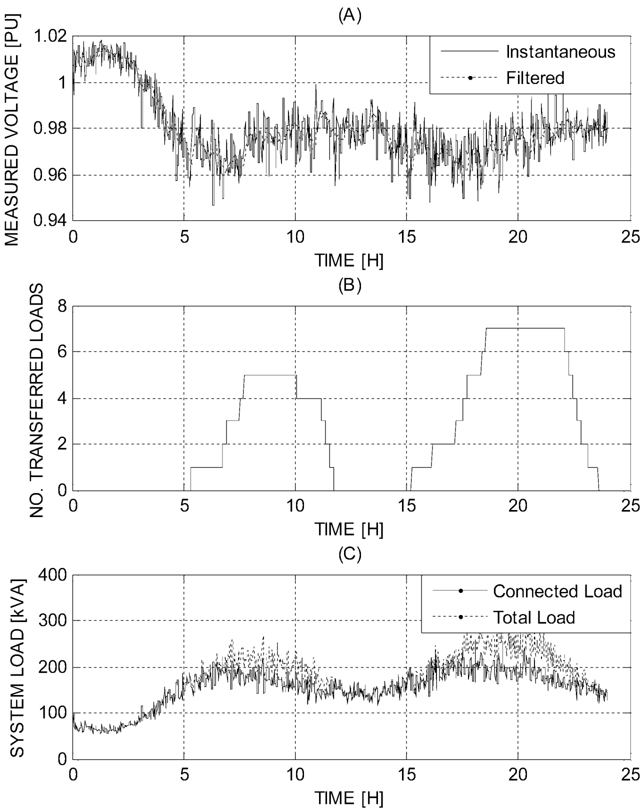


Fig. 8. Control system response.

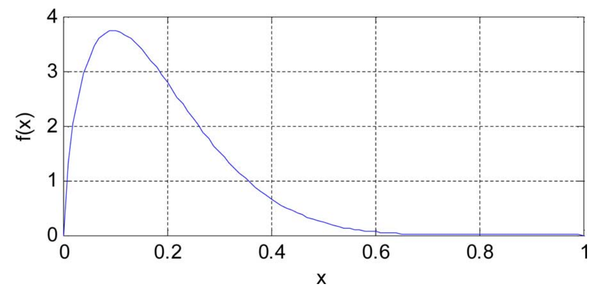


Fig. 9. Beta PDF with $\alpha = 1.73$ $\beta = 7.75$.

Fig. 8 shows the results of the time stepped simulation. Graph (C) shows the total system load (including connected and transferred customers) along with the total connected load. These curves have the typical "double humped" shape with morning and evening peaks. Please note that this is a synthesized load profile with the peak load matching the measured peak load and the remainder of the curve derived off a basic sinusoidal function. The random load variation of each load causes some randomness in the aggregated load (although the extent of the randomness is considerably reduced by the load diversity of the 88 loads). Graph (A) shows the average of the measured node voltages; both the instantaneous and the 15 minute moving average values and graph (B) shows the total number of transferred loads. As the total system load increases, in the early morning (t $<$5 h) the measured voltage drops. When the filtered measured voltage reaches 0.965 p.u. at time $\mathrm{t} = 5.5$ h (5:30 A.M.), the first load is transferred. This load is the highest priority load as calculated by expected voltage improvement (4). The transfer of load causes the voltage to increase, and the total and connected loads start diverging. As the load continues to increase additional loads are transferred to control the filtered voltage to above 0.965 p.u. This results in the minimum instantaneous voltage remaining above the specification of 0.94 p.u. As the morning peak abates, so the filtered voltage rises above 0.98 p.u. and loads are reconnected in reverse sequence.

The evening peak again results in the transfer of loads; however more loads are transferred (7) since the peak load is higher than the morning peak. The curve of the number of loads transferred shows the stable operation of the algorithm, despite a high level of random variation. There are no observable spurious operations. The system is also observed to track the system load variation well and maintain the measured voltage above the limit of 0.94 p.u. at all times.

Since the load is stochastic in nature, the operation of the algorithm should be checked over a wide range of simulations. The aforementioned simulation was repeated 50 times with similar results. The maximum number of transferred loads varies slightly from simulation to simulation depending on the load variations and was observed to always be in the range of 6–9 transferred loads. This confirms the analysis in Section IV-B that approximately ten generator sites are required to ensure that the voltage remains above its specification and means that considerable cost savings can be realized with this scheme compared with traditional network upgrades.

VII. Conclusion

This paper presents a novel peak load mitigation scheme using nonembedded diesel generators. The analysis, by way of a case study, has shown that this nonembedded peak shaving scheme can be effectively used by utilities in rural areas to improve the network voltage profile and avoid or delay network upgrades.

A methodology has been presented for determining the number of generators required and the best sites for those generators. Results for the case study show that a relatively small fraction of the customers is required to participate to maintain the voltage within its specification.

A hysteresis-based algorithm was presented as a means to control the system and results showed stable performance despite a high level of stochastic load behavior.

The results have proved extremely promising, and further investigation is continuing towards practical implementation.

Appendix
Beta Distribution

The beta distribution is a family of continuous probability distributions defined on the interval (0, 1) parameterized by two shape parameters denoted by α and β [15]. The probability density function (PDF) is given by

$$f(x;\alpha,\beta) = \frac{x^{\alpha-1}(1-x)^{\beta-1}}{\int_0^1 u^{\alpha-1}(1-u)^{\beta-1}du}.$$

The mean value is given by

$$\mu = \frac{\alpha}{\alpha + \beta}.$$

Fig. 9 shows the beta PDF, with $\alpha = 1.73$ and $\beta = 7.75$, as determined in [12] to fit middle-class domestic loads.

ACKNOWLEDGMENT

The authors would like to thank B. Cavanagh and A. Torrisi of Ergon Energy for their help and support.

REFERENCES

[1] Ergon Energy annual stakeholder report 2008/2009. [Online]. Available: http://www.ergon.com.au/about_us/download/2009_Reports/Annual_Stakeholder_Report_08-09.pdf

[2] R. C. Dugan, T. E. McDermott, D. T. Rizy, and S. J. Steffel, "Interconnecting single-phase backup generation to the utility distribution system," in *Proc. Power Eng. Soc. Transmission and Distribution Conf. Expo.*, 2001, vol. 1, pp. 486–491.

[3] K. Pandiaraj and B. Fox, "Novel voltage control for embedded generators in rural distribution networks," in *Proc. Int. Conf. Power System Technology*, 2000, vol. 1, pp. 457–462.

[4] K. Pandiaraj *et al.*, "Centralised control of diesel gen-sets for peak shaving and system support," *Proc. Inst. Elect. Eng., Gen., Transm. Distrib.*, vol. 149, pp. 126–132, 2002.

[5] R. C. Dugan and T. E. McDermott, "Distributed generation," *IEEE Ind. Appl. Mag.*, vol. 8, no. 2, pp. 19–25, Mar./Apr. 2002.

[6] N. I. Voropai and D. N. Efimov, "Operation and control problems of power systems with distributed generation," in *Proc. IEEE Power Energy Soc. Gen. Meeting*, 2009, pp. 1–5.

[7] K. Maki *et al.*, "Problems related to islanding protection of distributed generation in distribution network," *Proc. IEEE Power Tech.*, pp. 467–472, 2007.

[8] L. Mandeno, "Rural power supply especially in back country areas," *Proc. New Zealand Inst. Eng.*, vol. 33, pp. 234–271, 1947.

[9] W. D. Stevenson, *Elements of Power System Analysis*, 4th ed. New York: McGraw-Hill, 1982.

[10] F. Milano, "An open source power system analysis toolbox," *IEEE Trans. Power Syst.*, vol. 20, no. 3, pp. 1199–1206, Aug. 2005.

[11] H. L. Willis, *Spatial Electric Load Forecasting*, 2nd ed. New York: Marcel-Dekker, 2002, vol. 18.

[12] R. Herman and J. J. Kritzinger, "The statistical description of grouped domestic electrical load currents," *Elect. Power Syst. Res.*, vol. 27, pp. 43–48, 1993.

[13] R. Herman and S. W. Heunis, "Load models for mixed-class domestic and fixed, constant power loads for use in probabilistic LV feeder analysis," *Elect. Power Syst. Res.*, vol. 66, pp. 149–153, 2003.

[14] A. Wright and S. Firth, "The nature of domestic electricity-loads and effects of time averaging on statistics and on-site generation calculations," *Appl. Energy*, vol. 84, pp. 389–403, 2007.

[15] *Handbook of Beta Distribution and its Applications*, A. K. Gupta and S. Nadarajah, Eds. New York: Marcel Dekker, 2004.

Michael T. Wishart (M'91) received the Ph.D. degree in electrical engineering from the University of Natal, Durban, South Africa, in 1994.

Prior to joining Queensland University of Technology, Brisbane, Australia, in 2009, he spent 15 years in industry in various research-and-development roles in the power-electronics and power systems areas. These included periods working for Eskom, Rosherville, South Africa, and for various Schneider Electric subsidiaries in the Asia-Pacific region. His research interests are power systems, power electronics, and intelligent control.

Jon Turner received the B.Eng. degree from the University of Southern Queensland, Toowoomba, Queensland, in 1984.

He has been a Distribution Planner and System Modeling Specialist with Ergon Energy, Rockhampton, Queensland. Currently, he manages Ergon Energy's SWER Improvement Team and is working with universities and equipment manufactures to develop ways to modernize the single-wire earth return network. His interests are in the application of new technologies to power systems to improve their capability and performance.

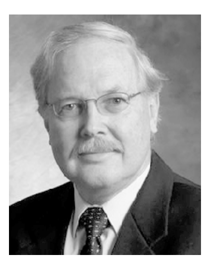
Lasantha B. Perera (M'03) received the B.Sc. (Eng.) degree in electrical engineering from the University of Moratuwa, Moratuwa, Sri Lanka, in 2000 and the Ph.D. degree in electrical and electronic engineering from the University of Canterbury, Christchuch, New Zealand, in 2006.

Currently, he is a Lecturer at Queensland University of Technology (QUT), Brisbane, Australia. Prior to joining QUT in 2008, he was a Senior Lecturer with the Department of Electrical Engineering of the University of Moratuwa. His research interests are in the areas of power-electronic applications in power systems, control of power systems, power quality, and power system protection.

Arindam Ghosh (S'80–M'83–SM'93–F'06) received the Ph.D. degree in electrical engineering from the University of Calgary, Calgary, AB, Canada, in 1983.

Currently, he is the Professor of Power Engineering at Queensland University of Technology (QUT), Brisbane, Australia. Prior to joining the QUT in 2006, he was with the Department of Electrical Engineering at the Indian Institute of Technology Kanpur, Kanpur, India, for 21 years. His interests are in control of power systems and power-electronic devices.

Prof. Ghosh is a Fellow of the Indian National Academy of Engineering.



Gerard Ledwich (M'73–SM'92) received the Ph.D. degree in electrical engineering from the University of Newcastle, Newcastle, New South Wales, Australia, in 1976.

He has been Chair Professor in Power Engineering at Queensland University of Technology, Brisbane, Australia, since 2000. His interests are in the areas of power systems, power electronics, and controls.

Dr. Brisbane is a Fellow of the Institute of Engineers Australia.